Code 01455

DEPARTMENT OF WATER AND POWER

FOR INTRA-DEPARTMENTAL USE ONLY

March 21, 1983

Mr. James H. Anthony
Project Director
Intermountain Power Project
931 General Office Building

Utah Air Conservation Committee (UACC)
Meeting on March 11, 1983 Concerning
Intermountain Power Project (IPP)
Air Quality Issues

This is to summarize issues regarding the IPP air quality permit raised by environmental groups, members of the UACC and the Director of the Bureau of Air Quality of the Utah Department of Health (DOH) at the regularly scheduled meeting of the UACC held on March 11, 1983.

A presentation was made by Mr. Sherman Young of the law firm of Ivie and Young of Provo, Utah, who apparently represents several environmental groups including the Sierra Club and the National Resource Defense Council. Mr. Young's position was that the IPP is not utilizing the Best Available Control Technology (BACT) for emissions of NOx and SO_2. He made reference to the California Air Resources Board (CARB) report "Guidelines for the Control of Emissions from Coal-Fired Power Plants" which concluded that BACT for NOx control is between 80 and 95 percent reduction and BACT for SO_2 control is approximately 95 percent reduction. He emphasized that existing emission controls on IPP require only a 37.5 percent reduction in NOx and a 90 percent reduction in SO_2 emissions and, therefore, fail to meet current BACT requirements. He also addressed the issue of acid rain and implied that further control of NOx emissions from IPP would reduce the likelihood of an increase in the acidity of Utah lakes.

Attached is a letter dated March 2, 1983 from Mr. Young to Dr. Brent Bradford, the Director of the Bureau of Air Quality, and also a document prepared by Mr. Young entitled "Proposed Comment for Submission to the Utah Air Quality Board in Reference to the Permitting Process for the Intermountain Power Project." These documents provide additional details of his position.

Dr. Bradford responded to Mr. Young's concerns by stating that he has contacted the CARB regarding their "Guidelines for the Control of Emissions from Coal-Fired Power Plants." However, the issue of BACT for NOx emissions would require additional detailed study by the Utah DOH before any conclusions could be drawn regarding this matter. Dr. Bradford also pointed out that the issue of acid rain is complex and that numerous studies are currently being conducted by government and industry to understand the causes and effects of acid rain.

Legal counsel to the Air Conservation Committee, Mr. Fred Nelson, stated that he would be unable to offer a legal opinion of the applicability of new BACT requirements for IPP until he had the opportunity to review the IPP air quality permit and the appropriate sections of the Utah Air Quality Regulations. It is presumed that his findings will be presented at the next meeting of the UACC.

The UACC, which consists of 11 members, expressed significant interest in the status of NOx control technology and its application to the IPP, the issue of acid rain, and the status of construction activity at the IPP. The Acting Chairperson of the UACC, Dr. Noel de Nevers, emphasized that the issue of BACT for NOx control is much larger than just IPP and is in fact a national issue. He implied that the Utah DOH should proceed with caution in any NOx BACT determinations due to the possible adverse consequences of setting a new precedent.

A motion was made and unanimously passed by the UACC which directed Dr. Bradford to investigate the following issues and report back to the UACC at the next meeting scheduled for April 15, 1983:

1. A study of the current status of BACT for NOx emissions and an evaluation of the CARB "Guidelines for the Control of Emissions from Coal-Fired Power Plants."

2. An evaluation of the air quality impacts from the IPP considering both proposed NOx control for IPP and NOx control specified in the CARB guidelines.

3. An evaluation of possible acid rain effects due to increased NOx emissions.

If you have any questions or if further information is required, please contact Mr. Stephen A. Clark on extension 3502.

PATRICK P. WONG
Manager
Civil, Structural Engineering
and Services

SAC:glh

Attachments

cc: w/Attachments

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March 2, 1983

FILE NO. ____

RECEIVED
MAR 3 1983
Utah State Div. Of
Environmental Health

Dr. Brent Bradford
Bureau of Air Quality
150 West North Temple
Suite 426
Salt Lake City, UT 84110-2500

Re: Nitrogen-Oxide Recovery Efficiencies of the Intermountain Power Project

Dear Dr. Bradford:

Since our last communication, I have made inquiries with respect to the current status of Selective Catalitic Reduction (SCR) technology.

On the 24th of February, 1983, I contacted by telephone Alan Goodley, Chief of the Energy Strategy Development Branch of the Stationary Source Control Division of the California Air Resources Board. In that telephone conversation, Mr. Goodley indicated to me that SCR is currently a commercially available technology for the control of NOx. Mr. Goodley also indicated that the three major boiler manufacturers in the United States; Combustion Engineering, Babcock Wilcox, and Foster Wheeler are all licensed to sell SCR technology in conjunction with their manufacture of boilers for coal-fired power plants.

You will note that on the inside cover of the study, "Proposed Guidelines for the Control of Emmissions from Coal-Fired Power Plants," of which you have a copy, that Mr. Goodley appears as a reviewer of that study. Mr. Goodley informs me that since that report was written, more SCR tests have been completed. These tests were completed at the Takehara Power Plant of the Electric Power Development Company of Japan. In that test SCR was installed on a 250 megawatt unit which has been in operation for over a period of one year. He also indicates that SCR technique is planned for nine coal-fired power plants in Japan. One of these plants, a Takehara Power Plant of 700 megawatts, will go into operation July 1, 1983. Another of the plants for which SCR is planned is a 1000 megawatt unit.

Mr. Goodley also provided me with information with respect to the costs of this technique. Cost information is also available on page iii of the prior referenced study. Mr. Goodley informs me that his calculations of the costs of increasing the recover efficiency of NOx of a 1500 megawatt unit, from 37.5% to between 80%-90% would be approximately 105 million dollars. He also indicates that that sum translates into approximately 5% of the total capital costs of such a project. On page iii of the aforementioned study, the authors state that the costs of upgrading the recovery efficiencies with respect ot NOx would be between 4 to 6 mills per kilowatt hour.

I forward this information so that you may be aware of the current status of the SCR technology. It would appear from preliminary examination that the additional cost to the IPP for recovery of these pollutants is neither excessive, nor overly burdensome. I am informed by Mr. Goodley that Air Resouces Board of California has taken the position that these costs are in line with the cost currently incurred by the use of NOx controls in automobiles.

Based upon this information, it would seem apparent that the technology for the control of NOx on this plant is commercially available. The remaining questions with reference to whether or not the IPP should be required to employ SCR technology involve the negative impacts of failing to require the application of SCR. I believe it will be the position of the groups which I have contacted that the costs of implementing this technology pale in comparison to the detrimental effects of failing to require that technology. With this in mind, we will attempt to acquire information substantiating the negative impacts of NOx pollutants. We also believe that the Bureau should turn a critical eye to the negative impacts of failing to require this technology. We believe that aesthetical, economic, health and safety factors are among many considerations which should be weighed in determining whether SCR technology should be applied to this project.

Your cooperation in this matter is greatly appreciated.

Sincerely,

Sherman C. Young

SHERMAN C. YOUNG

SCY:dea

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State of California

AIR RESOURCES BOARD

Proposed Guidelines for the Control of Emissions from Coal-Fired Power Plants

Prepared by:

Stationary Source Control Division

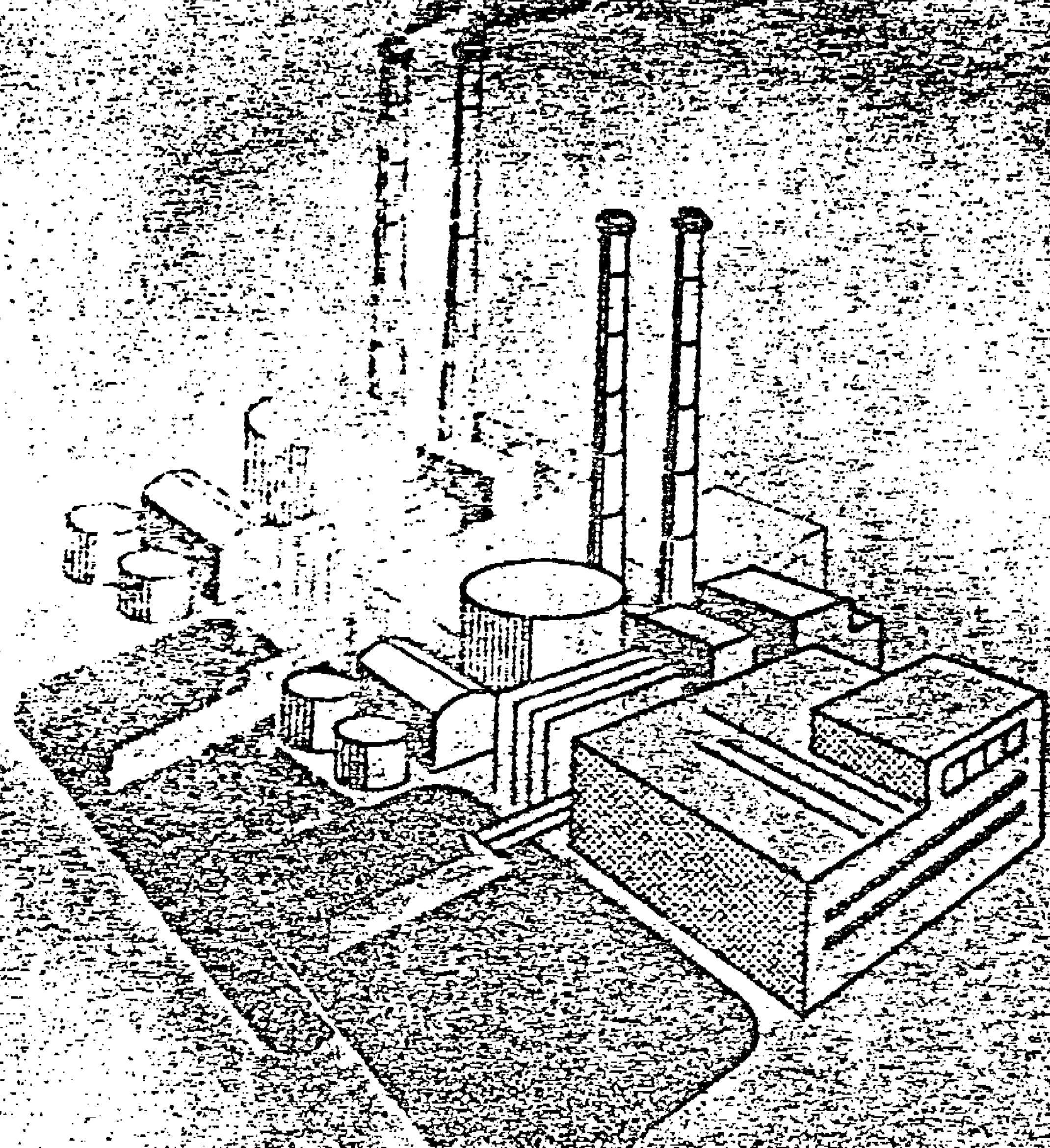
and

Regional Programs Division

Presented to the Air Resources Board
for Discussion on

June 24, 1981

FOR THE CONTROL OF EMISSIONS FROM COAL-FIRED POWER PLANTS



State of California
AIR RESOURCES BOARD
STATIONARY SOURCE CONTROL DIVISION
AND REGIONAL PROGRAMS DIVISION

State of California
AIR RESOURCES BOARD

Public Meeting to Discuss Proposed Guidelines
for the Control of Emissions
from Coal-Fired Power Plants

Scheduled for Consideration: June 24, 1981
Agenda Item No.:

SUMMARY

Two California utilities, Southern California Edison and Pacific Gas and Electric, have proposed coal-fired power plants for construction in California. Before such facilities can be built, they must meet air quality requirements. In California, these requirements include those established by the Environmental Protection Agency (EPA), the Air Resources Board (ARB), and the local air pollution control districts (APCDs).

Current EPA standards for coal-fired power plants are specified in the New Source Performance Standards (NSPS) applicable to such plants. These standards represent minimum control requirements and are applicable nation-wide. The staff has reviewed these standards as well as the actual permit conditions set by EPA and believes they do not usually represent the best available control technology.

Local districts' new source review rules require the application of the best available air pollution control technology on new major sources. In reviewing the applications for coal-fired power plants, the district in which the facility is being proposed must, therefore, make a determination of what is the best available technology. In order to assist these agencies

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in the review process and to ensure consistent requirements, the staff has developed proposed minimum guidelines for controlling emissions of sulfur dioxide, oxides of nitrogen, and particulate matter from new coal-fired power plants. These guidelines are being proposed as minimum guidelines; more stringent requirements may be considered by the local APCDs on a case-by-case basis.

In developing these guidelines, the staff has reviewed the work of EPA and other research organizations, observed similar facilities in Japan, and conducted a workshop with the utilities, manufacturers, and other state and local agencies.

The proposed minimum guidelines are: a 95 percent reduction of sulfur dioxide (SO_2) when the inlet concentration to the SO_2 control device exceeds 300 ppm, and a proportionately lower percent reduction resulting in an outlet concentration not to exceed 15 ppm when the inlet concentration to the SO_2 control device is equal to or less than 300 ppm; 0.005 grains per actual cubic foot (gr/ACF) for particulate matter; and 0.45 pound oer million (lb/mm) Btu of heat input for oxides of nitrogen (NO_x) below 50 percent of rated capacity, and 0.09 lb/mm BTU of heat input at 50 percent, and greater, of rated capacity. Guidelines for compliance determination and emission monitoring are also specified.

Control technologies needed to achieve the proposed guideline levels are readily available today. These include combustion modifications and ammonia-based flue gas treatment for NO_x, flue gas desulfurization for SO_2 and a baghouse for particulate matter.

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The capital cost of installing the control equipment necessary to achieve the proposed emission levels ranges from \$42 to \$66/kw for NO_x controls (in addition to combustion modifications), approximately \$34/kw for particulate matter controls, and \$96 to \$179/kw for SO_2 controls. Based on a total coal-fired power plant capital cost of \$1175 to \$1357/kw, the control equipment accounts for 15 to 21 percent of the total capital cost.

The levelized cost of installing the control equipment necessary to achieve the proposed emission levels ranges from 4.4 to 6.5 mills/kwh for NO_x controls (in addition to combustion modifications), 1.0 to 2.0 mills/kwh for particulate matter controls, and 6.7 to 12.4 mills/kwh for SO_2 controls. The sum of the control equipment levelized costs should represent somewhat less than 15 to 21 percent of the total plant levelized cost.

The staff has not identified any significant adverse environmental or other impacts that would result from installation of control equipment to meet the emission limits recommended by these guidelines.

deep reduction target in combination with combustion modifications. According to Exxon, the result of that study is based on the use of older technology, and recent advances in the DeNOx technology would result in an increase in DeNOx performance of 10 to 20 percent over the previous performance predictions.

This technology has not been demonstrated on a full-scale coal-fired boiler. There is concern that the fly ash from coal firing may deposit on interior grids, change gas flow patterns and temperature profiles, and foul or erode injection nozzles.

Thermal DeNOx results in the emission of unreacted ammonia from the stack, known as ammonia slip. Ammonia slip is estimated to be about 50 ppm at an ammonia to NOx mole ratio of 1.5:1. Also, ammonia reacts with sulfur trioxide in the flue gas to form ammonium bisulfate, which partially precipitates in the air preheater, and necessitates occasional plant shutdowns (perhaps every six months) for air preheater washing. Furthermore, Thermal DeNOx in utility boilers is generally only effective at high unit loads, with the efficiency of NO reduction falling off sharply with load.

[redacted]

The Selective Catalytic Reduction Process (SCR) is a commercial process for reducing NOx emissions in a flue gas stream. No other commercially available NOx reduction method can achieve the high reductions in NOx that can be achieved by SCR with such certainty and reliability. Its effectiveness is evidenced by its widespread use on oil-and-gas-fired, large and small units in Japan. The latest estimates indicate that there are approximately 100 commercial installations that use the SCR process to reduce NOx emissions from gas-and-oil-fired facilities (Ando, October 1980).

After successful application on oil and gas units to achieve 80-90 percent NOx emissions reductions, this process has been applied to reduce NOx emissions from coal-fired utility boilers in Japan. At the early stage of development for coal-fired units, the SCR process encountered several technical and operational problems. However, most of the problems have been solved, as demonstrated by extensive pilot scale testing (Itoh, et al., 1980; Wiener, et al., 1980; Narita, et al, 1980; Aoki, et al, 1980; Sengoku, et al., 1980; Levers, et al, 1980; Nakabayashi, et al, 1980) as well as commercial scale applications. These commercial scale applications are discussed in detail later in this section. In addition, SCR has been planned for many large coal-fired utility boilers in Japan (Table VII-5).

Published papers have identified major concerns regarding operational and technical aspects of using a selective catalytic reduction system on a coal-fired utility boiler. On the other hand, several papers indicate that many of these concerns have been resolved and provide data and other relevant information gathered at the pilot scale and commercial scale application of the SCR system.

(i) Concerns Regarding the Use of SCR

The major concerns regarding the operational and technical aspects of using an SCR system can be separated into two categories. The first, catalyst related, deals with catalyst life, catalyst activity, catalyst erosion, catalyst blinding, catalyst resistance to contaminants in the flue gas, and the catalyst as a promoter of SO_2 to SO_3

Table VII-5

Planned SCR Installations Coal-Fired Units in Japan

Power Company	Station & Unit	Capacity Treated with SCR, MW	Planned Completion
Electric Power Development Company	Takehara 1 1/	250	July 1981
	Takehara 3 1/	700	1983
	Matsuura 1 1/	1000	Unavailable
	2 1/	1000	Unavailable
Chugoku Electric Power Company	Shin-ube 1 2/	75	Sept. 1982
	Shin-ube 2 2/	75	Sept. 1982
	Shin-ube 3 2/	156	Aug. 1982
Joban Joint Power Company	Nakoso 8 2/	600	Dec. 1982
	Nakoso 9 2/	600	Apr. 1983

1/ Source: Electric Power Development Company, April 1981

2/ Source: "Measures for NOx Abatement of Thermal Power Stations in Japan", Ministry of International Trade and Industry, April 1981 oxidation. The second category, related to ammonia, includes ammonia control, ammonia carryover, and NH_3/SO_3 byproduct formation and its deposition on air preheaters.

a. Catalyst Related Concerns

The major concerns that have been identified relate to catalyst life, activity, erosion, and blinding effect. Most of the catalysts that have recently and are now being developed are based on titanium dioxide (TiO_2) with vanadium pentoxide as the active component. When these catalysts were introduced for oil firing, the manufacturers issued catalyst life guarantees of one year. Experience has shown that commercial installations using grid catalysts for oil firing have operated for two years without problems and without replacement of the original catalyst. As of April 1981, none of the commercial SCR units have required a catalyst change. In the meantime, the lifetime guarantees for oil firing have been extended to two years and the actual lifetime is expected to be even longer. That illustrates the performance and life of catalysts for oil-fired applications.

Although only two coal-fired utility applications have been in operation, those applications are achieving the design removal efficiencies without any difficulty. Catalyst life from three to five years is expected.

One of the concerns that has been frequently expressed relates to catalyst erosion attributed to fly ash. The catalyst that are being developed for coal-fired applications are shaped like a honeycomb, plate or pipe. The catalyst shape can be produced as a ceramic or metal substrate coated with the catalyst material or as a homogeneous form composed of purely catalyst material. The homogeneous catalyst shape is softer and can be eroded by the fly ash; however, the newly exposed catalyst is still catalytically active, and thus continues to perform. At the Shimonoseki power plant application, a "dummy" spacer (that is, a honeycomb section but with no active catalyst material in it) with the same shape as that of the catalyst was placed on top of the first catalyst layer, to maintain a uniform parallel gas flow and to prevent catalyst erosion by fly ash. Examination of the catalyst below the dummy layer shows no detectable erosion of the catalyst. The smooth operation of the SCR shows that this procedure apparently resolves the problem. In addition, several process vendors have demonstrated catalyst resistance to erosion of high grain loading flue gases.

Catalyst blinding by dust (fly ash) is another concern that has been expressed in the published papers. For an SCR system for coal-fired applications, two separate equipment arrangements can be used. One is called a "low dust" SCR system, in which the boiler flue gas is first passed through a hot-side electrostatic precipitator, and the cleaned flue gas flows through the catalyst. The other arrangement is called a "high dust" SCR system, in which the boiler flue gas flows through the catalyst without prior cleaning and the flue gas then flows through gas cleaning equipment after the catalyst reactor. Both the "low dust" and the "high dust" SCR systems have their advantages and disadvantages, which will be discussed in Chapter X. Here, the discussion is limited to how these two systems influence catalyst blinding.

Tests have shown that in the case of the "low dust" system, although the dust content in the gas is small, the dust consists of fine particles relatively rich in alkaline components and it tends to stick on the catalyst surface, particularly at the inlet face. This deposit of fine dust at the catalyst surface may cause blinding of the catalyst. This problem does not occur with the "high dust" system because the full ash load has a sandblasting effect which cleans the catalyst surface. Recent tests in Japan at the Nakoso plant, Joban Joint Power Co., and the demonstration at Shimonoseki plant of Chugoku Electric Power Company support the above conclusion (Ando, October 1980).

In addition to the blinding of the catalyst by dust, it is possible that the catalyst could be blinded by residual oil mist carry-over. Manufacturers of catalyst systems in Japan reported to the NOx study team that forced carry-over of residual oil mist in pilot plant tests resulted in blinding of the catalyst, rendering the catalyst ineffective. Since residual oil might be used in coal-fired power plants during start-up, such a problem is of concern. The Japanese manufacturers reported that blinding by oil mist carry-over has not occurred in any of the demonstration or commercial installations in Japan. Tests by manufacturers have shown that the residual oil coating of the catalyst cannot be removed by raising the temperature of the catalyst, although diesel oil coating can be removed, and avoided in operation, by raising the temperature of the catalyst to 350^{o} Centigrade (662^{o}F). It is possible that the residual oil mist coating could be removed if the catalyst were removed from the reactor and taken to a cleaning site. It is also possible that a by-pass of the reactor could be constructed, so that the reactor could be by-passed during start-ups or upset conditions which could result in an oil mist carry-over. However, it is obvious that steps can and should be taken in the operation of the power plant to avoid the possibility of residual oil mist carry-over.

Catalyst ability to resist all contaminants in the flue gas is another concern that has been expressed. However, pilot plant and commercial operation have shown that the catalyst can resist flue gas contaminants. For example, in one instance, the catalyst was operated successfully for over 9,000 hours continuously at a pilot scale coal-fired facility, and catalysts also have been in operation at two commercial coal-fired utility-boilers. Contaminants in the flue gas have not affected the catalyst performance up to April 1981 in those installations.

The oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) is increased by the catalyst. The catalysts that are now in use are composed mainly to titanium dioxide (TiO_2) with a small amount of vanadium pentoxide (V_2O_5). The V_2O_5 oxidizes SO_2 to SO_3. Sulfur trioxide can then react with ammonia (NH_3) and lead to the formation of ammonium compounds that may deposit on the air preheater and may also cause other environmental problems. To help correct this problem, new catalysts have been developed that suppress the oxidation of SO_2 to SO_3. Whereas the conventional catalyst could oxidize 2 to 4 percent of the SO_2 to SO_3, new catalysts have been developed that suppress the SO_2 to SO_3 oxidation to less than 0.5 percent. Figure VII-6 shows the performance of a catalyst designed to suppress SO_2 to SO_3 oxidation.

In summary, most of the concerns regarding the use of a catalyst for coal-fired boilers have been resolved. The blinding of the catalyst by oil mist carry-over has never occurred in commercial operation, and simple design techniques can preclude the possibility of blinding. Furthermore, the SCR systems at the two commercial scale coal-fired utility boilers have been operating smoothly without any problems. In fact, although the catalyst manufacturers guarantee the life of the catalyst for one year, they expect the catalyst to last for over two years (Ando, October, 1980; Nakabayashi, 1980).

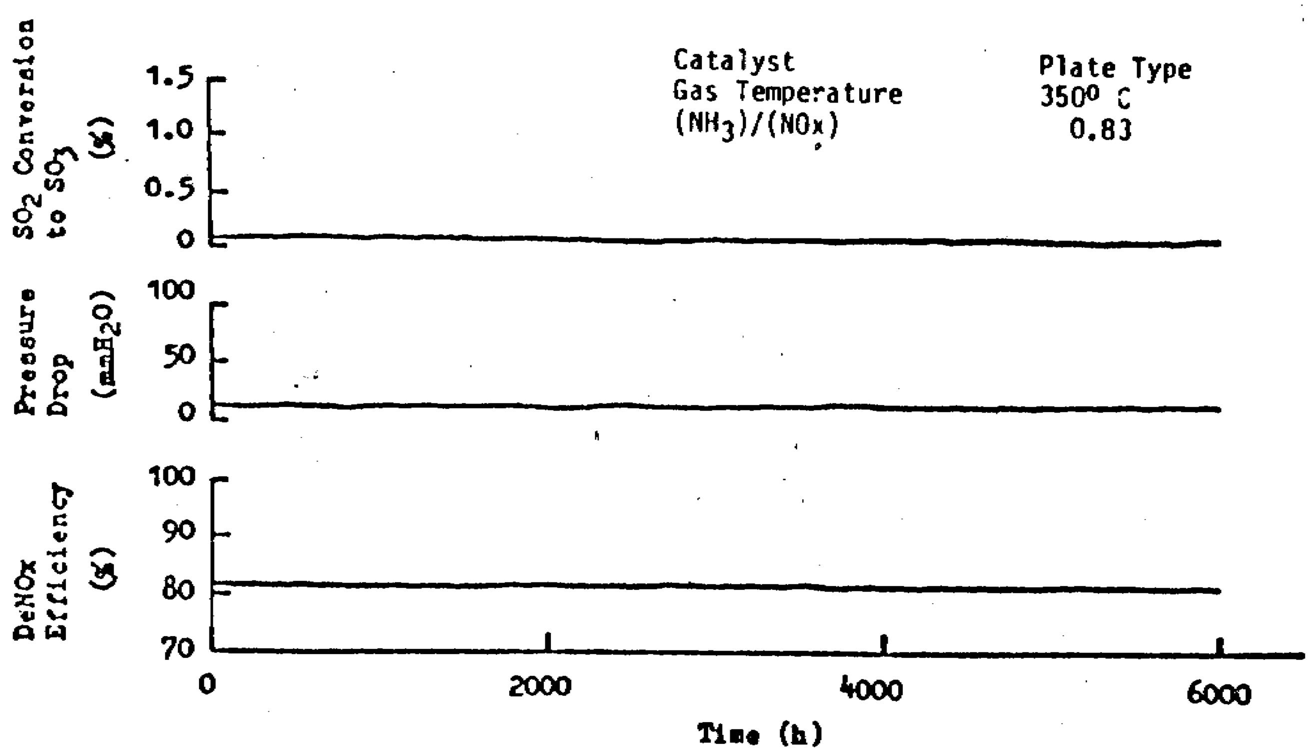
b. Ammonia Related Concerns

Concerns other than those related to catalysts are ammonia control and air preheater plugging by ammonium bisulfate deposition. The specific concerns are ammonia breakthrough; availability and reliability of instruments to monitor ammonia breakthrough; and air preheater plugging.

Ammonia injection in an SCR system employs a feed forward control based on a product of boiler load and reactor inlet NOx concentrations, and fine tuning supplied by feedback of the reactor outlet NOx concentration (Mobley, 1980; Jones, 1981). A small part of the injected ammonia does not react with NO and is carried out with the flue gas. This is known as slip or breakthrough. Many prefectures in Japan require utilities to limit ammonia slip to less than 10 ppm and this has resulted in the utilities requiring the SCR manu-

Figure VII-6

Pilot Plant Test of a Parallel Flow Reactor Treating Flue Gas from a Coal-Fired Utility Boiler



Source: T. Narita, et. al., "Babcock-Hitachi NOx Removal Process for Flue Gases from Coal-Fired Boilers" Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Vol. II, (October, 1980).

heater is restricted, and eventually the boiler must be shut down so that the air preheater can be washed. The accumulation is much more rapid in low dust systems than in high dust sytems because in high dust systems the dust removes the deposits.

If the air preheater is modified so that the intermediate and cold section elements are made into a continuous element, the deposition is minimized since there are not element ends for bulbs of deposits to form. Also, use of increased steam pressure and temperature with a round nozzle soot blower (rather than flare nozzle) at more frequent intervals reduces deposits. Finally, raising the air preheater temperature for a short period of time to above 300° C causes the ammonium bisulfate to evaporate. Adherence to these procedures, Gladelius and EPDC officials report, will eliminate the necessity for air preheater washing at times other than normal boiler outages for maintenance.

Operators of the Shimonoseki power plant (high dust system) and the Tomato Atsuma power plant (low dust system) reported to the NOx study team in April 1981 that air preheater plugging had not occurred.

In conclusion, it is the staff's belief that SCR is a commercially available technology for coal-fired boilers.

(ii) Commercial SCR Units on Coal-Fired Utility Boilers in Japan

a. Units in Operation

1. Shimonoseki Station Unit #1, Chugoku Electric Power Company

One of the SCR systems in operation viewed by the NOx study team was installed as a retrofit on a 175 MW coal-fired boiler, Unit #1 at the Shimonoseki Station of the Chugoku Electric Power Company. Unit 1 commenced operation in 1967 on coal and was switched to oil in 1970. In May, 1980, the unit was switched back to coal. In order to switch to coal, the utility had to reduce its overall NOx emissions to less than 350 ppm, averaged over an hourly basis. The utility decided to install an SCR system designed for 60 percent reduction to comply with the NOx emission limit. The details of the design basis of the SCR system are shown in Table VII-6. A picture of the reactor is shown in Figure VII-9.

The boiler #1 is a base load unit with a flue gas temperature at the reactor of from 350 to 370°C at full load. The unit is occasionally operated at 25 percent load, which results in a drop in the reactor flue gas temperature to below 300°C. To raise the temperature of the flue gas through the catalyst at 50 percent load, an economizer bypass system is installled to maintain the flue gas at the desired temperature.

Flow of flue gas through the reactor is downward to prevent plugging and the reactor is equipped with soot blowers (the soot blowers have not been used). High dust laden flue gas is taken from the economizer outlet and directed to the top inlet of the reactor and returned to the inlet of the air preheater. A "dummy" catalyst layer is located upstream of the five lower catalyst layers to prevent catalyst erosion by the fly ash and guide the flue gases through the reactor. A picture of the type of catalyst used in the reactor is shown in Figure VII-10.

To comply with the current regulation, a NH_3/NOx mole ratio of 0.51 is used, which reduced the NOx emission level by 50% from 500 ppm to 250 ppm. The observed ammonia slip and control efficiencies are shown previously in Figure (VII-7). Enough room has been provided in the reactor for the addition of sufficient catalyst to provide a long-term NOx reduction of 80%. The air preheater had an existing soot blower system on the cold side and was modified by adding a soot blower on the hot side and by altering the intermediate temperature elements. The hot side sootblower is now operated four times a day and the cold side sootblower is operated twice a day. Plugging of the air preheater by ammonium bisulfate has not occurred.

Plant operators are well satisfied with the SCR system. They expect catalyst life to be more than three years.

2. Tomato-Atsuma Plant, Hokaido Electric Power Company

The NOx study team also visited a new 350 MW coal-fired boiler at the Tomato Atsuma Power Plant of the Hokaido Electric Power Company. The local government required the NOx emissions from the new unit to be reduced below 200 Nm^3/hr (170 ppm at 6% O_2, average). The overall NOx level is reduced to below 200 ppm by using combustion modifications including staged combustion, flue gas recirculation, and low NOx burners. In order to further reduce the overall mass emissions, one-fourth of the flue gas is treated through an SCR system designed for 80 percent NOx removal.

The plant burns a low-sulfur coal (0.3% S). A hot-side electrostatic precipitator is used to reduce the dust content to approximately 45 mg/Nm^3. One fourth of the flue gas exiting from the hot ESP is directed to the SCR reactor. An economizer bypass system has been installed to maintain the flue gas in the reactor at the desired temperature at low loads.

The unit, with SCR, was started on July 15, 1980. By March 31, 1981 it had 5,270 operating hours. NOx removal efficiency of the SCR system is 83% with ammonia slip of 2 ppm.

The SCR is not operated below 50% load. No problem has been encountered with air preheater plugging. However, the probability of air preheater plugging is reduced because the flue gas exiting from the SCR is diluted by re-entering the duct containing the remaining three quarters of total flue gas flow. Soot blowers are operated on the air preheater three times per day. Soot blowers have been installed in the reactor but have not been used.

b. Planned Units

The Japanese have plans to use the SCR system on a number of additional coal-fired units in the future. Some of these units are already under construction. As previously presented, Table VII-5 shows the details and the scheduled completion year. The planned use of SCR underlines the confidence of the Japanese in the SCR technology and its application to coal-fired utility boilers.

(iii) Commercial Availability in the U.S.

The SCR system is commercially available in the U.S. for large coal-fired applications. The ARB staff, in December 1979, contacted a number of SCR process vendors to assess the availability of their control system for PG&E's Fossil 1 and 2 coal-fired power plants then scheduled to start operation in 1986. Several process vendors reported that they were prepared to offer their system with commercial guarantees (see Appendix B). One of those process vendors is Kawasaki Heavy Industries (KHI) which has sold an SCR unit for a coal-fired power plant in Japan. Another process vendor, IHI, is offering SCR units for coal application, and has also sold an SCR unit for a 600 MW coal-fired power plant in Japan.

(iv) Efficiency of NOx Reduction Using SCR

The SCR process is capable of achieving up to 90 percent control. However, while most of the industrial boilers operating in Japan are designed for NOx control in the 90 percent range, utility boiler applications commonly are designed for 80 percent control because, for a stipulated allowable ammonia slip, 80 percent NOx control requires less catalyst volume than 90 percent control. For an SCR system, if maximum ammonia slip is to be maintained at less than 5 ppm, to increase the NO_x removal efficiency from 80 to 90 percent would require a 35-50 percent increase in catalyst volume (Nakabayashi, et al., 1980). Since reactor and catalyst costs can contribute as much as 30 to 40 percent of the total SCR system capital cost, the overall capital cost can be reduced by approximately 10 to 15 percent because of this reduced requirement for catalyst alone. Also, there is an expected reduction in operating cost because the catalyst will eventually have to be replaced. Ammonia and energy consumption are also reduced for 80 percent control.

Figure VII-11 shows efficiency as a function of NH_3/NOx mole ratio. According to this figure, about 10 percent less ammonia would be required for 80 percent NOx control as compared to 90 percent NOx control. The actual reduction in ammonia usage by individual units may vary slightly depending upon the design and other operating variables of the SCR system. By reducing ammonia usage to 80 percent, ammonia slip also may be reduced as shown on Figure VII-11. The reduced ammonia slip, in turn, is expected to result in reduced potential for ammonium bisulfate precipitation on the air preheater. Reduced consumption of ammonia will probably result in a reduction in the requirement for carrier gas such as steam or air, and a smaller ammonia tank and vaporizer.

A Japanese consultant estimated the cost for installing an SCR system on a new coal-fired 700 MW utility boiler, operating at a 70 percent capacity factor. The consultant estimated that cost for both 80 and 90 percent control efficiency, for a high dust system and maintaining an ammonia breakthrough of between 5-10 ppm, and concluded that the total annualized cost for an SCR system operating at 80 percent efficiency would be about 30 percent less than for 90 percent control efficiency (Ando, October 1980).

From the above considerations, the staff concludes that an 80 percent reduction is the appropriate limit for using an SCR system for a coal-fired utility boiler.

3. Conclusion

Based on the above disucssion in this chapter, it can be concluded that NOx emission levels of 0.35 lbs per million Btu to 0.45 lbs per million Btu can be achieved by using combustion modification techniques. This, coupled with a flue gas treatment system, designed for 80 percent emission reduction, would result in NOx emission levels of 0.07 lb per million Btu to 0.09 lb per million Btu. The ARB staff believes that the technologies to achieve this range are currently available. The ARB staff recommends that a NOx emission level of 0.09 lb per million Btu should be selected as a final emission control level. This will ensure that the utility has operational flexibility, and it will also allow, whenever possible, the utility to operate the SCR system at less than 90 percent control efficiency. The staff believes that the level of 0.09 lb per million Btu should apply between 50 percent and 100 percent of full load, and a level of 0.45 lb per million Btu, as a minimum, should apply below 50 percent load.

[redacted]

In this section, the cost of the control technology to achieve the proposed level of control is discussed. The proposed level of control can be reached by using a combination of combustion modification techniques and an SCR system. The cost for combustion modification and for the SCR system are discussed below.

1. Cost of Combustion Modifications

The staff proposes that a level of 0.45 lbs per million Btu can be achieved by using combustion modification techniques. Based on discussion with boiler manufacturers and other consultants, the staff believes that it is very difficult to estimate the incremental cost of NOx controls for a utility boiler without evaluating the boiler design, type of fuel to be burned, and other site specific information.

PROPOSED COMMENT FOR SUBMISSION
TO THE UTAH AIR QUALITY BOARD
IN REFERENCE TO THE PERMITTING
PROCESS FOR THE INTERMOUNTAIN
POWER PROJECT

Sherman C. Young

1. Need to separate the utah attorney issue - Fred Young
lets review scrubber, baghouse - (we replaced the precipitator)
If they dete[illegible] that BACT review it will take 60-90 days & stop bonding.
BACT can't change or we'll in trouble.
We need air quality permit to be able to bond bond.

Mtg 2:00 Friday

Diamond Lil

I. THE AIR QUALITY APPROVAL ORDER SHOULD BE DENIED UNLESS THE PROJECT UTILIZES THE MOST EFFICIENT POLLUTION CONTROLTECHNOLOGY AVAILABLE.

A. AS PROPOSED, THE PROJECT DOES NOT UTILIZE THE MOST EFFICIENT TECHNOLOGY FOR CONTROL OF OXIDES OF NITROGEN.

1) Oxides of Nitrogen

The Intermountain Power Project does not employ the most efficient technology currently available for control of oxides of nitrogen. As proposed, the project will operate at a control efficiency of 37.5 percent. This will result in emissions of 61,371 tons of oxides of nitrogen per year, and 2,147,985 tons emitted over the life of the project.(Personal communication, Utah Air Quality Board, 8 January 1983). Over its life-time the plant will emit 1,976,143 tons of nitrogen-oxide which could be removed with proven technologies which are currently available.

In contrast to a recovery efficiency of 37.5 percent proposed by the I.P.P., California has determined standards which that state would require of a plant such as the I.P.P. These standards require California facilities to remove between 80% and 95% of nitrogen-oxide emissions. California has recently determined that these levels of control recovery are technologically proven and commercially available.("Proposed Guidelines for Control of Emissions from Coal Fired Power Plants", State of California, Air Resources Board, Stationary Source Control Division and Regional Programs Division, 24 June 1981). Based upon that study the California Air Resource Board made the following findings (quoted in part):

> WHEREAS, the Board staff has also reviewed recent developments in air pollution control technology for coal fired power plants;...
>
> the Board finds :
>
> That SCR [selective catalytic reduction] flue gas treatment systems have been demonstrated to reduce flue gas NOx concentrations by over 80% and as much as 95% over the load range of 50% to 100% of full load. (Resolution 81-42; Air Resources Board, State of California, 24 June 1981).

The Board also found that in addition to SCR, combustion modification techniques in conjunction with SCR,

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would result in total NOx emissions reduction to 0.09 lb./million BTU, or less, over the load range of 50% to 100% of full load. In contrast, the I.P.P. will reduce NOx emissions to a level of 0.60 lb./million BTU. (I.P.P. Air Quality Approval Order, Division of Environmental Health, State of Utah Dept. of Health, 3 December 1980).

Additionally, removal of oxides of nitrogen through a two stage combustion process is also available. Two stage combustion is defined as firing all fuel below stoichiometric amounts of primary air in the first stage of combustion, followed by injecting air in a second stage, where upon burnout of the fuel is completed. The formation of NO in the first stage is limited and the removal of heat between stages kinetically limits the formation of NO when excess air is added to the second stage. Experience shows that a 90% reduction in NO emission can be achieved in this manner.(Van Nostrand's Scientific Encyclopedia, 5th Ed. p.1809, Van Nostrand Rienhold Company,New York, Cincinnati, Atlanta, Dallas, San Francisco).

a) Ozone

Control of oxides of nitrogen is desirable because these oxides contribute to air pollution in two significant ways. Oxides of nitrogen play a significant role in the depletion of the ozone, $O3$. Ozone is a critical component of the atmosphere because it filters out the sun's ultra-violet rays which can cause skin cancers.(Id p.52). The chemical reaction through which this depletion occurs is as follows:

$$NO + O3 \rightarrow NO2 + O2$$

$$NO2 + O \rightarrow NO + O2^{-}$$

("Stratospheric Pollution",186 Science 335-338, 25 October 1974).

b) Acidic Precipitation

Oxides of nitrogen are significant in acidic precipitation. Recent studies indicate that acidic cloud water is a significant problem in parts of the West and that oxides of nitrogen are substantial contributors to the acidic conditons.("Chemical Composition of Acid Fog", 218 Science 677, 12 November 1982). This study, completed by the California Institute of Technology concluded that the highest acidic concentrations ever measured (pH 2.2 - 4.0) were measured in the Los Angeles basin and that nitric acid (HNO3) and ammonium ion (NH4+) were substantial components of the acidity. The study strongly suggests that emissions of NOx are responsible for the presence of these nitrogen derivatives because the concentration ratio of NO3- to SO4-- in the measured fog water was about 2.5, which was comparable to the reported emmission rate (218 Science at 679). Additionally, the study found that the dominant ions in the fog water were NH4+, H+ NO3-,and SO4--, and that the highest concentrations were observed "after days of dense haze"(Id). Further, it was found that condensation of water resulted in the dilution of acidity and that evaporation led to higher concentrations of the acidic ions (Id). These findings are consistent with general principles of chemistry and the theory that emissions of NOx are in part responsible for acidic atmospheric water.

Acid rain has recently become an issue national in scope. (See, Press Release, Izaak Walton League of America, 8 November 1982, Arlington, Virginia). While it is well established that New England and the Northern Central regions suffer from and are sensitive to acid rain, the West, as demonstrated by the above cited study, is not immune to the problem. Indeed, areas of Utah have recently been identified by the E.P.A.as being acid rain sensitive (See, Sulfur-Oxides p6. this comment). Currently Utah has pollution problems, and pollution is particularly heavy in times of thermal inversions. This was most recently demonstrated by the heavy dense smog which covered Salt Lake and Utah Valleys in the winter of 1981-1982. As the number of sources of pollution increase with increasing population, Utah's pollution problem and exposure to acid precipitation will increase. In view of the long lag time necessary for installation of pollution control equipment, it is critical that appropriate precautions be taken today to ensure the health and quality of life for our children and grandchildren. In the case of the I.P.P., these precautions take the form of requiring the most efficient control technology presently available.

c) Tourism

In addition to the chemical basis for requiring the reduction of emissions from the project, aesthetic and fiscal factors compel the conclusion that NOx emissions must be reduced to the lowest level feasible. Atmospheric haze, is an unavoidable impact of the project. (See I.P.P. Final EIS p.9-5). This haze is the precursor to acidic precipitation in the presence of atmospheric water and creates a dense brownish-yellow haze in the absence of atmospheric moisture. The Final EIS indicates that a discoloration of the atmosphere can be expected over the Sevier Desert. (This finding is based upon the conclusion that the prevailing winds blow from the north, a finding that is specifically challenged in other sections of this comment). This discoloration can be expected to impact on other areas of Utah and the brownish-yellow haze will detract from the aesthetic quality of Utah's natural splendor. It can be expected that the quality of that scenery will deteriorate, and with that deterioration, a corresponding reduction in tourist traffic.

2) Sulfur-Dioxide

The I.P.P. does not use the most effective technology available for control of sulfur dioxide emissions. Technology which is currently available will remove 95 percent or more of sulfur emissions. The I.P.P. proposes to remove only 90 percent. With two units operating the porject will emit 3.55 tons of SO2 daily, 1,296 tons annually and 51,830 tons over the expected life of the power plant. Those emissions could be reduced by one-half if the most effective control . . technology was implimented.

a) Acid Rain

Removal of SO2 is desireable because it is a principal constituent of acid rain. Recent scientific studies have linked atmospheric SO2 with. acid rain. These studies indicate that SO2 is probably oxidized in the presence ofatmospheric water to create sulfuric acid, H2SO4.(218 Science 6679. The studies conclude that in Los Angeles morning fog and low cloud along the coast are strongly correlated with high SO2 aerosol concentrations in the Los Angeles basin during the afternoon.(G.R.Cass,thesis, California Institute of Technology, Pasadena(1977) Environ. Qual. Lab. Mem. 5, cited in 218 Science at 678) These studies contribute to a growing body of scientific data which document that sulfur-dioxide emissions play a major role in acidic precipitation.
As outlined below removal of SO2 is important in maintaining the quality of life for both plant and animal populations.

b) General Characteristics of Sulfuric Acid

Sulfuric acid is one of the most powerful acids known. Organic substances, such as cellulose wich contain hydrogen and oxygen in the ratio of one to two, can be charred by sulfuric acid. Sulfuric acid can be highly destructive to human tissue.and is used to clean rust from iron in the galvinization process.(General Chemistry; Nebergall, Schmidzt and Holtzclaw, 4th Ed. 1972 p.484-488).In short, it is a highly destructive acid which should not be allowed to accumulate in the air we breathe.

c) Sulfur Caused Deaths

Redently released studies have linked sulfur pollution to 51,000 deaths per year in North America. A congressional study released last October also indicates that if sulfur pollution remains constant it could cause 57,000 deaths per year by the turn of the century.(Salt Lake Tribune, 27 September 1982, p.A3).

c) Death and Defoliation of Forests

Acid rain, of which H_2SO_4 is a major constituent, has been linked to widespread death of trees in Vermont Forests. Although the findings are still under investigation and not conclusive, researchers have not been able to find another cause of the deaths, either disease or insect pest.(Salt Lake Tribune, 14 October 1982,p.A4).The studies show that in areas of high acid rainfall the plants which have died contain high concentrations of aluminum in the outer, stunted, growth rings. Aluminum is toxic to plants and normally insoluble in soils, but is liberated by acid allowing it to be absorbed by plants (Id). Additionally, other chemical ions such as cadmium, zinc, lead and copper which are toxic to living systems, have been found in high concentrations in areas of high acid rainfall. (See also "Potential For Acid Snowmelt in the Wasatch Mountains", Jay J. Messer, et al., Water Quality Series #UWRL/Q-82/06, Utah Water Research Laboratory, Logan, Utah)

d) Sulfur Pollutants from the I.P.P. will Significantly Impact the Wasatch Front.

Wind studies near the I.P.P. site indicate that winds in the area blow from the south to the north and will carry the pollutants to the Utah and Salt Lake Valleys. Windrose studies by Utah State Climatologist, Arlo Richardson, indicate that the prevailing winds blow from the southern to the northern quadrant approximately fifty percent of the time. These studies, also known as polar coordinate plots, were based on data collected for 3.5 years used to determine the alignment of the runways at the Delta Air Port, and concluded that the winds blew from the south 42% of the time. Similar studies completed at Milford also conclude that the winds are from the south for approximately 50% of the time. The figures in that study indicate that the wind blows from the southern quadrant 52% of the time. It is obvious that airborne pollutants will be transported in the direction of the prevailing winds, and in this case, to the Wasatch Front.(Personal Communication, 18 november 1982).

e) Highly Desirable Areas of Utah Have Been Determined to be Acid Sensitive.

A map of acid rain sensitive areas has been released by the Environmental Protection Agency. (Total Alkalinity of Surface Waters - -A National Map, by James M. Omernik and Charles F. Powers, Corvallis Environmental Research Laboratory, U.S.E.P.A., Corvallis, Oregon). Information from this study shows that four counties in Utah have been determined to be acid rain sensitive. Included in these counties. are the Uintah Mountains and the Uintah Primative(?) area. The Uintahs are sensitive to acid rain because the surface waters contain only 200-399 microequivalents of alkaline per liter, an amount insufficient to neutralize acidic precipitation. It can be expected that acid rain falling in the Uintahs will have a detrimental effect on the wildlife and foliage of those mountains. Additionally, to the degree that wildlife hab in Utah is destroyed by acidic precipitation, a corresponding decline can be expected in wildlife and game, and the revenues that the state derives from the sale of fish and game licenses as well as the expectures for accomodations made by out-of-state hunters during the hunting season. It is clear that failure to require stringent recovery technologies on the I.P.P. has consequencies that range beyond those which are only immediately apparent.

f) Acid Rain In The Uintahs May Result in the Presence of Toxic Ions in Culinary Waters of the Wasatch Front.

Additionally, it is not uncommon for geologic intrusions such as the one which created the Uintah Mountains to contain trace amounts of toxic ions. To the extent that the Uintah Mountain Intrusion and its derivative soils contain ions toxic to humans,(see 214 Science 38) which can be mobilized by acidic precipitation, human health along the Wasatch Front will be adversely effected. This is because the Central Utah Project will bring water from the Uintah Mountains to the Wasatch Front for culinary purposes. Unlike organic substances, which can be purified through chlorination, toxic metallic ions are not removed by that process. Therefore, those ions could be mobilized and transported in the waters brought by the CUP. A corresponding decline in the quality of health for those drinking the water might be expected. Additionally, recent studies in Utah, Colorado, New Mexico,and Washington have shown that acidification of precipitation occurs despite the absence of heavily industrialization immediately upwind.(Jay J. Messer supra, p. This finding is in general agreement with the finding that total acid deposition is approximately twice the value of acid deposited through precipitation; the remaining one-half being deposited in the absense of precipitation.(Dr.Micheal Oppenheimer, testimony before the Colorado Air Quality Control Commission, 3 December 1982). This would indicate that the total acid deposition in the Uintahs or other areas of Utah is double those amounts which are deposited in the form of precipitation. Therefore, mobilization of ~~any~~ this ions could occur sooner than an initial interpretation of those studies might infer.

g) A Recovery Efficiency of 95% of Flue Gas SO2 is Technologically Feasible, Economically Reasonable and Commercially Demonstrated.

As in the case of oxides of nitrogen, the State of California has determined that state's Best Available Control Technology for coal fired power plants. The California Air Resources Quality Board found that 95% or greater recovery control efficiency of SO2 from flue gases was "technologically feasible, economically reasonable and commercially demonstrated without coal pretreatment or sulfur credits."(State of California, Air Resources Board, Resolution 81-42, 24 June 1981).The citizens of Utah are entitiled to no less protection than the citizens of the state of California and Utah should require these more stringent recovery efficiences.

h) Conclusion

As proposed, the I.P.P. will emit the equivalent of 26 railroad car loads of SO2 into the Utah atmosphere annually. By requiring the most efficient control technology available that figure could be reduced by one-half. As documented above it is clearly in the best interest of Utah and its citizens to require these controls.